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DTE Energy

10 CFR 50.73

September 21, 2006
NRC-06-0065

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington D C 20555-0001

Reference: Fermi 2
NRC Docket No. 50-341
NRC License No. NPF-43

Subject: Licensee Event Report No. 2006-003, "Automatic Reactor Shutdown Due To Loss of Division 1 Power"

Pursuant to 10 CFR 50.73(a)(2)(iv)(A), Detroit Edison is hereby submitting the enclosed Licensee Event Report (LER) No. 2006-003. This LER documents an automatic reactor shutdown as a result of a loss of Division 1 power.

No commitments are made in this LER.

Should you have any questions or require additional information, please contact Mr. Ronald W. Gaston of my staff at (734) 586-5197.

Sincerely,

cc: D. H. Jaffe
C. A. Lipa
NRC Resident Office
Regional Administrator, Region III
Supervisor, Electric Operators,
Michigan Public Service Commission

IE22

NRC FORM 366 (6-2004)	U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB: No. 3150-0104 Expires 6/30/2007
LICENSEE EVENT REPORT (LER) (See reverse for required number of digits/characters for each block)		Estimated burden per response to comply with this mandatory collection request: 50 hours. Reported lessons learned are incorporated into the licensing process and fed back to industry. Send comments regarding burden estimate to the Records and FOIA/Privacy Service Branch (T-5 F52), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by internet e-mail to infocollects@nrc.gov, and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202 (3150-0104), Office of Management and Budget, Washington, DC 20503. If a means used to impose an information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

1. FACILITY NAME	2. DOCKET NUMBER	3. PAGE
Fermi 2	05000341	1 OF 5

4. TITLE
Automatic Reactor Shutdown Due To Loss of Division 1 Power

5. EVENT DATE			6. LER NUMBER			7. REPORT DATE			8. OTHER FACILITIES INVOLVED	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV NO	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER 05000
07	29	2006	2006	- 003 -	00	09	21	2006	FACILITY NAME	DOCKET NUMBER 05000

9. OPERATING MODE: 1

10. POWER LEVEL: 100%

11. THIS REPORT SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR§: *(Check all that apply)*

☐ 20.2201(b)	☐ 20.2203(a)(3)(i)	☐ 50.73(a)(2)(i)(C)	☐ 50.73(a)(2)(vii)
☐ 20.2201(d)	☐ 20.2203(a)(3)(ii)	☐ 50.73(a)(2)(ii)(A)	☐ 50.73(a)(2)(viii)(A)
☐ 20.2203(a)(1)	☐ 20.2203(a)(4)	☐ 50.73(a)(2)(ii)(B)	☐ 50.73(a)(2)(viii)(B)
☐ 20.2203(a)(2)(i)	☐ 50.36(c)(1)(i)(A)	☐ 50.73(a)(2)(iii)	☐ 50.73(a)(2)(ix)(A)
☐ 20.2203(a)(2)(ii)	☐ 50.36(c)(1)(ii)(A)	☒ 50.73(a)(2)(iv)(A)	☐ 50.73(a)(2)(x)
☐ 20.2203(a)(2)(iii)	☐ 50.36(c)(2)	☐ 50.73(a)(2)(v)(A)	☐ 73.71(a)(4)
☐ 20.2203(a)(2)(iv)	☐ 50.46(a)(3)(ii)	☐ 50.73(a)(2)(v)(B)	☐ 73.71(a)(5)
☐ 20.2203(a)(2)(v)	☐ 50.73(a)(2)(i)(A)	☐ 50.73(a)(2)(v)(C)	☐ OTHER
☐ 20.2203(a)(2)(vi)	☐ 50.73(a)(2)(i)(B)	☐ 50.73(a)(2)(v)(O)	Specify in abstract below or in NRC Form 366A

12. LICENSEE CONTACT FOR THS LER

FACILITY NAME	TELEPHONE NUMBER (Include Area Code)
Robert J. Salmon – Principal Licensing Engineer	(734) 586-4273

13. COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT

CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX
B	FK	87	B093	Y					

14. SUPPLEMENTAL REPORT EXPECTED		15. EXPECTED SUBMISSION DATE	MONTH	DAY	YEAR
☐ YES *(If yes, complete 15. EXPECTED SUBMISSION DATE)*	☒ NO				

ABSTRACT *(Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines)*

On July 29, 2006 at 15:50 hours EDT, a reactor scram and main turbine / generator trip occurred due to a partial loss of feedwater accompanied by a reactor recirculation system scoop tube lock. The loss of the south reactor feedwater pump and scoop tube lock were caused by a loss of Division 1 electrical power which occurred when the transformer 2 differential relay tripped 120 kV bus 101 during an energization of transformer 2. This led to a reactor scram on reactor low water level 3. The lowest reactor vessel water level reached was 110 inches which is below the reactor low water level 2 setpoint. Plant safety system actuations and isolations occurred as expected, and the standby feedwater system was started and used to maintain reactor level in the normal range. Reactor pressure control was maintained using the turbine pressure regulator with the main condenser available as the heat sink. The event occurred during an energization of transformer 2 and was caused by a trip of the transformer 2 differential relay which is designed to preclude such a trip. Inaccurate risk perception by the Fermi organization was identified as the primary organizational cause of the event since work was allowed to be performed without adequate consideration of risk to generation that resulted in a loss of bus 101 and reactor scram. The transformer and associated relaying were removed from service, and a plant stand down (training session) was held with site personnel on the scheduling issues involved. Risk sensitive and safety related work was postponed until adequate risk reviews were performed. The plant was restarted, and the main generator was synchronized to the electrical grid on August 1, 2006.

17. NARRATIVE *(If more space is required, use additional copies of NRC Form 366A)*

Initial Plant Conditions:

Mode 1
Reactor Power 100 percent

Description of the Event

On July 29, 2006 at 15:50 hours EDT, a reactor scram and main turbine [TA] / generator [TB] trip occurred due to a partial loss of feedwater accompanied by a reactor recirculation system scoop tube lock. The partial loss of feedwater and scoop tube lock were caused by a loss of Division 1 electrical power. The loss of Division 1 electrical power occurred when the transformer 2 differential relay tripped 120 kV bus 101 during an energization of transformer 2. The loss of bus 101 resulted in the loss of power to the operating south reactor feedwater [SJ] pump (SRFP) turbine control and lube oil pump which caused the hydraulically operated stop and control valves to close resulting in a loss of feedwater flow from the SRFP. The loss of Division 1 power also resulted in reactor recirculation scoop tube locks (as designed). The north reactor feed pump continued to operate. The plant is designed with an automatic runback of the recirculation system to allow continued operation following the loss of a single feed pump. However, the loss of bus 101 also resulted in the locking of the reactor recirculation pump speeds (scoop tube lock), disabling the runback feature. This led to a reactor scram on reactor low water level 3 (Level 3) since a single feed pump is not able to maintain reactor water level at 100% power operation. The lowest reactor vessel water level reached was 110 inches which is below the reactor low water level 2 (Level 2) setpoint. When SRFP control oil pressure recovered, feedwater flow from the SRFP recovered. Recovering feedwater injection from the SRFP following the scram caused an increase in reactor water level and a high reactor water level 8 (Level 8) shutdown of the HPCI, RCIC, and reactor feedwater pumps.

Reactor water Level 3 was subsequently reached, and the standby feedwater [SJ] system was started and used to maintain reactor level in the normal range. Reactor steam was sent to the condenser [SG] via the main turbine bypass lines. Reactor pressure control was maintained using the turbine pressure regulator with the main condenser available as the heat sink. Reactor dome pressure peaked at about 1045 psig. With reactor pressure maintained below the Safety Relief Valve (SRV) setpoints, none of the SRVs lifted.

The reactor protection system (RPS) [JD] performed as expected, and all rods fully inserted into the core. Both the HPCI and RCIC systems auto-started in response to a reactor low water level 2 (Level 2) injection signal, however, only the RCIC system injected into the vessel. The Level 2 signal was only present for about 2.7 seconds until reactor water level recovered above Level 2. The HPCI injection logic is such that the Level 2 signal must be present until HPCI startup has completed. This includes time for the hydraulic pressure from the HPCI Auxiliary Oil Pump to develop enough pressure to open the HPCI turbine steam isolation valve (E4100F067) and time to stroke open the motor operated HPCI turbine steam isolation valve (E4100F001). It took about 12 seconds before steam was admitted to the HPCI Turbine. Thus, the HPCI main pump outlet valve (E4150F006) did not open due to the short duration of the Level 2 signal. This is consistent with the HPCI system design.

The Division 1 Emergency Diesel Generators automatically initiated and supplied the Division 1 ESF buses.

Reactor water Level 3 isolations [JM] occurred as expected. These include isolation Group 4 (Residual Heat Removal Shutdown Cooling and Head Spray), Group 13 (Drywell Sumps), and Group 15 (Traversing In-core Probe System) isolations. Reactor water Level 2 isolations also occurred as expected. These include isolation Group 2 (Reactor Water Sample), Group 10 (Reactor Water Cleanup Inboard), Group 11 (Reactor Water Cleanup Outboard), Group 12 (Torus Water Management System), Group 14 (Drywell and Suppression Pool Ventilation), Group 16 (Nitrogen Inerting), Group 17 (Reactor Recirculation Pump Seals and Primary Containment Radiation Monitoring), and Group 18 (Primary Containment Pneumatic Supply).

A 4-hour notification of this event was made to the NRC in accordance with 50.72(b)(2)(iv)(A), 50.72(b)(2)(iv)(B) and 50.72(b)(3)(iv)(A) at 19:19 hours ET on July 29, 2006 (EN 42738). An update was made on July 31, 2006 which indicated that there was no ECCS (HPCI) injection, as expected, due to the short duration of the Level 2 signal.

Subsequent to the event, oil samples were obtained from transformer 2 and the transformer 2 load tap changer. Those samples were tested and determined to be normal and not indicative of an internal fault. The transformer 2 differential relay was inspected and bench tested satisfactory. The differential current transformers and the associated control scheme also tested satisfactory.

Transformer 2 was isolated from the Division 1 electrical bus, and the associated relaying was removed from service. The plant was restarted, and the main generator was synchronized to the electrical grid on August 1, 2006.

Cause of the Event

The event occurred during an energization of transformer 2 and was caused by a trip of the transformer 2 differential relay which is designed to preclude such a trip. The most likely cause of the trip is improper transformer 2 differential (87T-2) relay settings or a spurious trip of that relay that resulted in the isolation of 120 kV bus 101 which feeds the plant's Division 1 busses through system service transformer 64. The differential relay was bench tested satisfactory after the event, however, additional testing of the relay is planned. Spurious trips of this type can occur due to transformer inrush currents as determined by transformer residual magnetism and on the precise moment (portion of the sine wave) the disconnect poles close on the transformer disconnect switch. Relays of this type use a second harmonic blocking scheme to preclude trips during transformer energization. Although these schemes have been effective in avoiding trips for most inrush events, industry experience indicates they have not been totally effective in precluding inadvertent relay trips.

Inaccurate risk perception by the Fermi organization was identified as the primary organizational cause of the event since work was allowed to be performed without adequate consideration of risk to generation that resulted in a loss of bus 101 and reactor scram. There was an insufficient understanding of work scope, effects of transformer inrush currents, and the potential for impact on plant operations. Transformer 2 had been recently installed as a plant modification and was energized in an unloaded state for about 2 months. The transformer was deenergized to continue the work under the modification package. If the work package reviewers had understood that the transformer disconnect switch was to be cycled again and understood the potential for losing bus 101, the

1. FACILITY NAME	2. DOCKET	6. LER NUMBER			3. PAGE
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Fermi 2	05000341	2006	-- 003 --	00	4 OF 5

decision making would have been affected regarding whether or when to perform the work. Contributing causes included a lack of strict adherence to the augmented quality program which governs work activities by non-Fermi personnel in the 120 kV and 345 kV switchyards (the maintenance liaison was not involved in all phases of the associated modification), the work was not included in the plan of the day, and the work package lacked sufficient detail for Operations to determine the status of components. Since the need to manage the work to prevent impact on plant operations was not recognized, the work was authorized to proceed without strict adherence to the work management process, and mitigation strategies were not developed.

Analysis of the Event

The generator and turbine trips functioned as designed. The reactor scrammed as designed from the Low Level 3 signal. The plant response to the loss of division 1 power was as expected and was enveloped by the qualitative analysis provided for the loss of alternating power transient described in the UFSAR.

There was no challenge to the integrity of the reactor coolant system or the main steam system. The lowest reactor water level during the transient was determined to be approximately 110 inches above top of active fuel which is below the reactor water Level 3 and Level 2 isolation trip setpoints. Reactor water Level 3 and Level 2 isolations occurred as expected. These include Group 2 (Reactor Water Sample), Group 4 (Residual Heat Removal Shutdown Cooling and Head Spray), Group 10 (Reactor Water Cleanup Inboard), Group 11 (Reactor Water Cleanup Outboard), Group 12 (Torus Water Management System), Group 13 (Drywell Sumps), Group 14 (Drywell and Suppression Pool Ventilation), Group 15 (Traversing In-core Probe System) isolations, Group 16 (Nitrogen Inerting), Group 17 (Reactor Recirculation Pump Seals and Primary Containment Radiation Monitoring), and Group 18 (Primary Containment Pneumatic Supply) isolations. The highest reactor pressure received was about 1045 psig which is below the safety relief valve setpoints; 5 each at 1135, 1145, and 1155 psig. Subsequent to the unit trip, reactor pressure was adequately controlled using the main turbine bypass valves, and reactor water level was controlled using the standby feedwater system.

Since the generator, turbine and reactor protection systems performed as designed, and since plant response was enveloped by the UFSAR transient analyses, there was no undue risk to the health and safety of the public as a result of this event. The event was also analyzed from a probabilistic safety analysis (PSA) perspective, and was determined to be of low safety significance.

Corrective Actions

Transformer 2 has been tested and determined not to be the cause of the differential relay trip. The transformer and associated relaying have been removed from service until further testing of the differential trip relay is performed or until further actions are identified to ensure an inadvertent trip of bus 101 does not occur upon re-energization of transformer 2.

A plant stand down (training session) was held with site personnel discussing the need for a strict adherence to scheduling milestones and the human performance barriers built into the scheduling process. Recent plant work related organizational failures were discussed during the training session including this event. Management expectations for schedule adherence and a strict adherence to procedures and processes were discussed during the training session, and plant personnel were informed that they would be held accountable for their actions in this regard. All risk sensitive and elective safety related work was postponed until the risk of plant impact was verified and, as needed, appropriate mitigation strategies were developed. Risk reviews were also performed on the modification work orders in progress.

This event has been documented in the Fermi 2 corrective action program, CARDs 06-24914 and 06-24954. Investigation is continuing and is expected to result in the identification of additional corrective actions to minimize future occurrences of this type. Further testing is to be performed to determine whether there is a specific defect in the transformer 2 differential relay or relay settings. Plant procedures and training are also being evaluated for potential improvements. Any further corrective actions identified as a result of these evaluations will be tracked and implemented commensurate with the established processes and priorities of the corrective action program.

Additional Information

A. Failed Components: Transformer 2 Differential Relay
Component: Transformer differential relay
Function: Isolates transformer 2 faults by isolating bus 101 from the 120 kV system
Manufacturer: Basler Electric
Model Number: BE1-87T, Style E1E A1Y D1N0F
Failure Cause: Apparent failure of relay to block trip on transformer energization

B. Previous LERs on Similar Problems:

LER 2003-002-01 discussed the loss of all offsite power due to a regional electrical grid disturbance which occurred on August 14, 2003. The cause of that event was a complete loss of Division 1 and Division 2 power due to a loss of the electrical grid power supplies. The cause of the event discussed in this LER is related to 120 KV switching operations with all of the incoming power supplies intact. Therefore, because the causes of the events differ significantly, the corrective actions taken to address the loss of power event are unrelated, and would not be expected to be effective in precluding the current event.